July 31, 2015

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Midcontinent Independent System Operator, Inc.’s and MISO Transmission Owners’ Compliance Filing for Order No. 1000, Regarding Interregional Coordination with PJM, Docket No. ER13-1943, et al

Dear Secretary Bose:

In compliance with the requirements of the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) December 18, 2014 Order on Compliance Filings in these proceedings, the Midcontinent Independent System Operator, Inc. (“MISO”) and the MISO Transmission Owners (collectively with MISO, the “Filing Parties”) submit for filing proposed revisions to the Joint Operating Agreement between MISO and PJM Interconnection, L.L.C.

1 Order on Compliance Filings, 149 FERC ¶ 61,250 (Dec. 18, 2014) (“December 18 Order”).
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(“JOA”)\(^3\) to comply with the requirements of the December 18 Order regarding Order No. 1000’s interregional planning and cost allocations requirements as applicable to MISO and PJM, LLC.

The Filing Parties, PJM and the PJM Transmission Owners have engaged in extensive outreach and coordination. Significantly, the parties have reached full agreement on all points at issue in this compliance filing and have collaborated in drafting their transmittal letters. Accordingly, PJM and MISO are hereby submitting (by separate filings being made contemporaneously) parallel tariff language to comply with the December 18 Order. The parties request that the proposed revisions be made effective as of January 1, 2014, as ordered in the December 18 Order.

I. BACKGROUND

A. Order No. 1000’s Interregional Transmission Coordination and Cost Allocation Requirements

Order No. 1000\(^4\) expanded on the planning requirements of Order No. 890\(^5\) by requiring each public utility transmission provider to establish procedures with each of its neighboring transmission planning regions for the purposes of coordinating and sharing regional transmission plans to identify possible interregional transmission facilities that are more efficient and cost-effective than separate, regional, solutions to each region’s needs.\(^6\) Order No. 1000 also required neighboring transmission planning regions to jointly evaluate those interregional facilities that both regions had identified through their regional processes, including those proposed by transmission developers and stakeholders.\(^7\)

To facilitate interregional evaluation and cost allocation, the Commission required each public utility transmission provider to (1) explain in their Tariffs how stakeholders and developers can propose interregional transmission facilities for joint evaluation;\(^8\) and (2)

\(^3\) The JOA is filed with the Commission as Rate Schedule No. 5 to MISO’s Open Access Transmission, Energy, and Operating Reserve Markets Tariff (“Tariff”).


\(^6\) *Order No. 1000-A* at P 494 (citing Order No. 1000 at P 398).

\(^7\) Id. at P 522.

\(^8\) Id.
develop, with each neighboring planning region, a common set of methods for allocating the costs of a new interregional facility among the beneficiaries in each region.\textsuperscript{9} The Commission required that the common set of methods satisfy six interregional cost allocation principles.\textsuperscript{10} A proposed interregional transmission project would become eligible for interregional cost allocation by being selected in the regional plans of the two neighboring planning regions in which the facility is to be located.\textsuperscript{11}

\section*{B. MISO’s First Compliance Filings}

On July 10, 2013, the Filing Parties submitted their proposals for compliance with Order No. 1000’s interregional coordination and evaluation requirements in two related filings (collectively the “MISO Compliance Filings”). The first filing, made in Docket No. ER13-1943 (“JOA Filing”), proposed revisions to Article IX of the JOA to implement the agreement between MISO and PJM regarding evaluation and cost allocation of proposed interregional projects (“JOA Filing”).\textsuperscript{12} The JOA Filing proposed clarifications and modifications to the existing JOA, which the Filing Parties stated already met or exceeded many of Order No. 1000’s requirements.\textsuperscript{13} The second filing, made in Docket No. ER13-1945, proposed modifications to Attachment FF of MISO’s Tariff to comply with the Commission’s requirement that the Tariff identify MISO’s interregional arrangements that are in the form of agreements. (“Attachment FF Filing”).\textsuperscript{14} The Attachment FF Filing proposed language identifying the interregional coordination procedures proposed in the JOA Filing.\textsuperscript{15}

On July 10, 2013, PJM and the PJM Transmission Owners made separate filings proposing competing modifications to the JOA\textsuperscript{16} (“PJM Filing”) due to a disagreement with

\textsuperscript{9} Order No. 1000 at PP 578, 582.
\textsuperscript{10} Id. at PP 603, 622-693. The six cost allocation principles are: (1) costs must be allocated in a way that is roughly commensurate with benefits; (2) there must be no involuntary cost allocation to non-beneficiaries; (3) a benefit to cost threshold ratio cannot exceed 1.25; (4) costs must be allocated solely within the transmission planning region or pair of regions unless those outside the region or pair of regions voluntarily assume costs; (5) there must be a transparent method for determining benefits and identifying beneficiaries; and (6) there may be different methods for different types of transmission facilities.
\textsuperscript{11} Id. at P 400.
\textsuperscript{12} MISO and MISO TOs’ “Compliance Filing for Order No. 1000, Regarding Interregional Transmission Project Coordination and Cost Allocation with PJM Interconnection, L.L.C., Docket No. ER13-1943 (July 10, 2013).
\textsuperscript{13} Id.
\textsuperscript{15} Id.
\textsuperscript{16} PJM Interconnection, LLC, “Submission of Interregional Transmission Coordination
MISO relating to certain aspects of interregional cost allocation. However, both the PJM Filing and the JOA Filing agreed on common language related to interregional transmission coordination and the interregional allocation of costs for Cross-Border Market Efficiency Projects (“CBME Projects”).

The JOA Filing and Attachment FF Filing proposed JOA and Tariff modifications relating to: (1) interregional coordination in general; (2) data exchange and facility identification; (3) procedures for joint evaluation of projects; (4) transparency and stakeholder participation; (5) elimination of Cross Border Baseline Reliability Projects (“CBBR Projects”) from the JOA; and (6) cost allocation methods for CBME Projects and CBBR Projects.

C. December 18 Order

On December 18, 2014, the Commission entered an Order accepting in part the Filing Parties’ JOA Filing and Attachment FF Filing effective January 1, 2015. The December 18 Order accepted these filings in part, subject to a further compliance filing to be made within sixty days, as discussed below.

1. Interregional Coordination in General

The Filing Parties proposed to comply with the interregional transmission coordination requirements of Order No. 1000 through modifications to the existing JOA that largely tracked those proposed by PJM’s compliance filings. The Commission partially accepted MISO’s proposal, holding that MISO complied with the requirement to coordinate with neighboring transmission providers and that MISO had proposed substantially similar coordination language to that proposed by PJM. However, the Commission found that there were some non-substantive and unnecessary differences between MISO and PJM’s proposed language and that the two RTOs had submitted competing provisions regarding interregional cost allocation and directed that these be reconciled.

The December 18 Order also found that the Filing Parties’ and PJM’s proposed JOA language identifying interregional projects partially complied with Order No. 1000. The Commission noted that the JOA described CBME Projects and CBBR projects but did not use the term “interregional transmission facility,” which Order No. 1000 defined as “a transmission

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17 JOA Filing at 2; December 18 Order at P 34.
18 See generally, JOA Filing; Attachment FF Filing.
19 December 18 Order at P 41.
20 Id. at P 37.
21 Id.
facility that is located in two or more transmission planning regions.” The Commission directed the Filing Parties to modify the JOA, on compliance, to clarify that the JOA’s interregional planning process and the related cost allocation methods apply both to (1) transmission facilities located in one RTO, and (2) transmission facilities that cross the seam.\textsuperscript{22}

2. Data Exchange and Facility Identification

The MISO Compliance Filings and PJM’s filings proposed using two formal joint planning committees and \textit{ad hoc} issue-specific committees to facilitate interregional coordination.\textsuperscript{23} The two proposed formal committees are the Joint RTO Planning Committee (“JRPC”), which would be composed of staff from the two RTOs; and (2) the Interregional Planning Stakeholder Advisory Committee (“IPSA C”), which would be open to stakeholders.\textsuperscript{24} MISO and PJM proposed meetings at least annually for the two formal committees and procedures governing the development of a Coordinated System Plan (“CSP”) considering transmission needs from both regions.\textsuperscript{25}

The MISO Compliance Filings and PJM’s filings proposed to modify their current JOA process governing data exchange to:

(1) provide a schedule for rotating responsibility for data management coordination for certain activities between the RTOs;
(2) require that certain categories of data (including models and predictions for power flow, system stability, production cost and contingency lists) be exchanged annually; and
(3) require that other categories of information—including studies, plans, short circuit models, and system maps—be exchanged upon request.

MISO and PJM would harmonize the format of all such exchanged information.\textsuperscript{26}

The Commission partially accepted the Filing Parties’ and PJM’s data exchange and facility identification proposals, finding that these provided for the exchange of sufficient information to allow each RTO to plan its own system accurately and reliably and to assess the impact of conditions existing on the system of the other party.\textsuperscript{27} The Commission also found that the data exchange procedures, including the development of a CSP, were sufficient to identify potential interregional transmission facilities and secure participation in multi-party studies.\textsuperscript{28} However, the Commission found that MISO and PJM had not complied with Order

\textsuperscript{22} Id. at P 39-40.
\textsuperscript{23} JOA Filing at 10.
\textsuperscript{24} Id.
\textsuperscript{25} December 18 Order at PP 45-46.
\textsuperscript{26} Id. at PP 49-51.
\textsuperscript{27} Id. at P 61.
\textsuperscript{28} Id. at PP 61-64.
No. 1000’s requirement to explain how stakeholders and developers can propose interregional transmission facilities for joint evaluation.\(^{29}\)

3. Procedures for Joint Evaluation

The Filing Parties and PJM proposed to jointly evaluate identified transmission solutions as part of the CSP study process, under the auspices of the JRPC, which would prepare a report to the Boards of both RTOs for approval and implementation, after completing the CSP study.\(^{30}\) The Filing Parties and PJM further proposed to revise the CSP study process to require that the planning models will be developed consistent with the models and assumptions used in each RTO’s most recently completed planning cycle.\(^{31}\)

The Commission partially accepted the Filing Parties’ and PJM’s proposed joint evaluation procedures, finding that they were consistent with Order No. 1000’s requirements that the joint evaluation of interregional projects occur in the same general timeframe as each region’s individual consideration of a proposed interregional transmission project and that the procedures describe the studies to be used.\(^{32}\) The Commission also found that the proposed CBBR and CBME Project types properly accounted for each region’s reliability and economically driven transmission needs.\(^{33}\) However, the Commission found that the Filing Parties’ and PJM’s proposal failed to consider regional transmission needs driven by public policy requirements as part of the evaluation of an interregional transmission facility. Accordingly, the Commission directed MISO and PJM to submit, on compliance, revisions to the coordination procedures to account for proposals that resolve transmission needs driven by public policy.\(^{34}\)

4. Transparency and Stakeholder Participation

The Filing Parties and PJM proposed that each RTO provide its own website for communicating information related to interregional transmission coordination procedures, with oversight from the JRPC. Stakeholders could provide feedback through submitting issues to, and reviewing issues identified by, the JRPC Committee and the IPSAC. Stakeholders also would be able to comment on studies, identified solutions, and the final CSP study report, before it is posted.\(^{35}\) In addition, the Filing Parties and PJM proposed JOA revisions to require each RTO to prepare an annual regional transmission planning report that identifies joint/cross-border issues

\(^{29}\) Id. at P 65.
\(^{30}\) Id. at P 69.
\(^{31}\) Id. at P 71.
\(^{32}\) Id. at PP 91-92.
\(^{33}\) Id. at P 93.
\(^{34}\) Id. at PP 89, 94.
\(^{35}\) Id. at PP 102-104.
and solutions. The Commission held that MISO and PJM’s proposal complied in full with Order 1000 in this respect.

5. Elimination of Cross Border Baseline Reliability Projects from the JOA

The Filing Parties agreed with PJM’s proposal to use the current CBME Project cost allocation method to comply with Order 1000. But the Filing Parties disagreed with the PJM TOs’ proposal to also use the JOA’s existing, flow-based, interregional cost allocation method for CBBR Projects. Instead, the Filing Parties proposed that CBME Projects be eligible for interregional cost allocation and that CBBR Project cost sharing be based on: (1) whether the project is a tie-line; and (2) whether neighboring transmission owners in MISO and PJM voluntarily agree to share costs. The Filing Parties also proposed that future CBBR Projects not be eligible for interregional cost allocation as projects approved in the RTOs’ regional transmission plans for purposes of regional cost allocation.

The Commission rejected the Filing Parties’ proposal to remove CBBR Projects from the JOA. The Commission agreed with the Filing Parties that CBBR Projects, as currently defined in the JOA, cannot be selected in MISO’s regional transmission plan for purposes of cost allocation because baseline reliability projects no longer are eligible for regional cost allocation under MISO’s Tariff. However, the Commission found that it had specifically ordered MISO and PJM to include cost allocation provisions for this project category.

6. Cost Allocation: Treatment of CBME Projects and CBBR Projects

The Filing Parties proposed to use the JOA’s existing cost allocation provisions to comply with Order No. 1000’s interregional cost allocation requirements, except for the CBBR Projects. PJM proposed to use these provisions for both CBBR Projects and CBME projects.

The Commission rejected MISO’s proposed removal of the JOA’s CBBR Project provisions but conditionally accepted the remainder of the Filing Parties’ and PJM’s proposals.

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36 Id. at P 104.
37 Id. at PP 107-109.
38 JOA Filing at 19-28.
39 December 18 Order at PP 127-129.
40 Id. at P 130.
41 Id. at P 191.
43 Id. at P 185.
44 Id. at P 177.
subject to further compliance.\textsuperscript{45} The Commission found that the Filing Parties’ proposals satisfied five out of the six cost allocation principles set forth in Order 1000, but did not satisfy principle 6—requiring at least one cost allocation methodology for each type of transmission project.\textsuperscript{46}

The Commission agreed with the Filing Parties that the CBBR Project category was an unsuitable vehicle for interregional cost sharing,\textsuperscript{47} leaving the CBME Project category as the sole mechanism for interregional allocations. The Commission also found that the CBME Project category applies only to projects that address economic transmission needs, leaving no viable mechanism for reliability and public policy-driven projects.\textsuperscript{48} Thus, the Commission found that both the Filing Parties’ and PJM’s proposals failed to satisfy cost allocation principle 6’s requirement that there be at least one cost allocation method available for each type of project.\textsuperscript{49} The Commission therefore directed the Filing Parties to submit a further compliance filing that either revised the existing project categories to account for projects addressing reliability and public policy needs or to propose new cost allocation methods for the same.\textsuperscript{50}

\textbf{D. Stakeholder Involvement & Extension Requests}

MISO and PJM have engaged in extensive discussion with each other and with their respective stakeholders in the months since the December 18 Order was issued. On January 26, 2015, the Filing Parties and PJM filed a Joint Motion requesting a 120-day extension of time to submit their compliance filing. The Commission granted the extension of time on January 30, 2015, extending the deadline to submit the compliance filing until June 16, 2015.\textsuperscript{51} On June 9, MISO and PJM requested a second, 45-day extension, which was granted on June 16, 2015.\textsuperscript{52} This additional time has allowed the Filing Parties, PJM and the PJM Transmission Owners to conduct numerous meetings, reach agreement on all aspects of this filing, and to coordinate the drafting of their transmittal letters.

\textsuperscript{45} \textit{Id.} at P 185.
\textsuperscript{46} \textit{December 18 Order} at P 190.
\textsuperscript{47} \textit{Id.} at P 191.
\textsuperscript{48} \textit{Id.} at P 190.
\textsuperscript{49} \textit{Id.}
\textsuperscript{50} \textit{Id.} at PP 193-194.
II. COMPLIANCE WITH THE DIRECTIVES OF THE DECEMBER 18 ORDER

The Filing Parties address each of the remaining Commissions directives from the December 18 Order below:

A. Harmonization of JOA Language Between MISO and PJM; Cost Allocation

The December 18 Order partially accepted the Filing Parties’ proposed revisions to the JOA that were made to comply with Order No. 1000’s requirement that each pair of neighboring transmission planning regions develop the same language to describe the interregional transmission coordination procedures for that particular pair of regions.\(^{53}\) The Commission found, however, that some minor differences existed between MISO’s and PJM’s proposals that are not necessary to reflect the perspective of the filer. Accordingly, the Commission directed MISO and PJM, on compliance, to:

1. propose identical language to govern the interregional transmission coordination between MISO and PJM, with any differences limited to those needed to reflect that the discussion is from the perspective of either MISO or PJM; and

2. include a common interregional cost allocation method consistent with FERC directives.\(^{54}\)

The Filing Parties propose revisions to comply with these first directives by eliminating the unnecessary differences between PJM and MISO’s coordination language in the JOA. MISO and PJM have coordinated their compliance regarding this directive and have agreed on consistent language that will control.

The Filing parties propose to comply with the Commission’s directive to submit a common interregional cost allocation method consistent with the Commission’s directives by revising JOA section 9.4.3, \textit{et seq.} as discussed in section III.E of this transmittal letter, below.

B. Revisions to the Definition of Interregional Projects in the JOA

The December 18 Order also found that the Filing Parties’ and PJM’s proposed JOA language identifying interregional projects partially complied with Order No. 1000 but did not use the term “interregional transmission facility,” which Order No. 1000 defined as “a transmission facility that is located in two or more transmission planning regions.” The Commission directed the Filing Parties to modify the JOA, on compliance, to state that the cross-border transmission planning process and the related cost allocation methods apply both to (1) transmission facilities located in one RTO that provide benefits to both, and (2) transmission facilities that cross the seam.\(^{55}\)

\(^{53}\) \textit{December 18 Order} at P 37.
\(^{54}\) \textit{Id.}
\(^{55}\) \textit{Id.} at P 39-40.
The Filing Parties and PJM have agreed on the following proposed revision to section 9.4.3.1 of the JOA to comply with the Commission’s directive:

Interregional Projects must be: (1) physically located in both the MISO region and the PJM region or (2) physically located wholly in one transmission planning region but jointly determined and agreed upon to provide benefits to the other transmission planning region or both transmission planning regions.

This proposed definition makes clear that the interregional transmission planning process and the related cost allocation methods “apply to transmission facilities located in one RTO and transmission facilities that cross the seam and are located in both RTOs” as directed by the Commission. 56

C. Revisions to Clarify How and Where Interregional Projects Can Be Proposed for Joint Evaluation; Explanation of Transparency

The Commission directed MISO and PJM to submit on compliance JOA and Tariff revisions that either: (1) clarify how stakeholders and developers can propose interregional projects to each RTO for joint evaluation, or (2) allow stakeholders and developers to propose interregional projects to a joint RTO committee operating under transparent procedures. 57 The Commission further directed the Filing Parties and PJM to explain how the process is transparent so that stakeholders and transmission developers understand why their interregional transmission project does or does not move forward in the process.

The Filing Parties propose to comply with these directives by revising JOA Section 9.3.5.2.b(iv) to state:

The Coordinated System Plan study will consider the identified issues reviewed by the JRPC and IPSAC for further evaluation of potential remedies consistent with the criteria of this Protocol and each Party’s criteria. Stakeholder input will be solicited for potential remedies to identified issues, which includes stakeholder and transmission developer proposals for Interregional Projects. The study scope developed under Section 9.3.5.2(b)(ii) will include the schedule for acceptance of such stakeholder Interregional Project proposals including supporting analyses that address issues identified in the JRPC solicitation. 58

56 *December 18 Order* at P 40.
57 *Id.*
58 See Tabs A and B, Proposed JOA section 9.3.5.2.b.(iv).
The Filing Parties propose to additionally comply with these directives by revising JOA Section 9.3.5.2.b(viii) to state:

Transmission upgrades identified through the analyses conducted according to this Protocol and satisfying the applicable Protocol and regional planning requirements will be included in the Coordinated System Plan after the conclusion of the Coordinated System Plan study and applicable regional analyses. After the conclusion of the Coordinated System Plan study, any project included in the Coordinated System Plan and designated for interregional cost allocation, if not already engaged in the regional review process, will be submitted to the regional processes for review according to Section 9.3.5.2(x).

This proposed language implements the Commission’s directive by “creat[ing] a point in its regional transmission planning process where stakeholders and transmission developers can submit ideas for interregional transmission projects that MISO then submits to the Joint RTO Planning Committee.”59 That point will be when stakeholder input is solicited for potential remedies to issues identified in the CSP study.

In response to the Commission’s directive to explain how the process will enable developers and stakeholders to understand why a particular project did or did not move forward in the process, the Filing Parties propose revisions to JOA section 9.3.5.2(b)(ix). This section already requires the JRPC to publish a report on each RTO’s website that documents the CSP study, “including the transmission issues evaluated, studies performed, solutions considered, and, if applicable, recommended Interregional Projects with the associated cost allocation to the Parties pursuant to Section 9.4.3.1.” As presently written, this report would satisfy half of the Commission’s transparency directive by explaining the justification(s) for projects that did move forward in the evaluation process. To implement the second half of the Commission’s directive and provide an explanation for why proposed interregional projects did not progress through the process, the filing parties propose to revise this section to additionally require that “explanations why proposed Interregional Projects did not move forward in the process will be provided in the final CSP study report.”60 With these proposed revisions, the JOA now requires explanations for both projects that do and do not move forward in the process and makes those explanations publicly available.

D. Revisions to Coordination Procedures to allow Regional Consideration of Interregional Facilities Driven by Public Policy

The Commission directed MISO and PJM to submit revisions to the coordination procedures for evaluating interregional transmission projects to account for proposals that

59 December 18 Order at P 65.
60 See Tabs A and B, Proposed JOA section 9.3.5.2.b.(ix).
resolve regional transmission needs driven by reliability and public policy. The Filing Parties propose to comply with this directive by adopting revisions to JOA sections 9.2.1, 9.2.2, 9.3, 9.3.5.2.b.(v) & 9.3.5.2.b(vi), 9.4.3.1.3, and 9.4.3.2.3, which revisions expressly reference public policy needs as being included in the scope and assumptions, and models for the CSP study and provide for the exchange and consideration of information relating to such projects. Taken together these revisions will allow for the integration of public policy-driven projects into the interregional project analysis.

E. Revisions to Cost Allocation Procedures to Allow for the Selection and Cost Allocation of Interregional Projects Addressing Reliability and Public Policy Needs

The Commission directed MISO and PJM to revise their currently existing CBBR and/or CBME allocation method(s), or propose a new interregional cost allocation method(s), that apply to interregional transmission projects addressing regional reliability transmission needs and regional public policy needs, which must allow for such interregional projects to be eligible for selection in both MISO’s and PJM’s regional transmission plans for purposes of cost allocation or to describe how their revised cost allocation method(s) account for regional transmission needs driven by reliability or by public policy. The Commission gave MISO and PJM discretion to decide whether to address this directive by modifying the existing CBBR/CBME cost allocation framework to account for public policy and reliability driven projects or to propose a new cost allocation method to account for such projects.

After careful consideration and discussion with each other and their respective stakeholders, MISO and PJM have agreed to address the Commission’s directives by proposing revisions to JOA section 9.4, to establish a new project type, “Interregional Projects” for purposes of cost allocation. As set forth in proposed JOA section 9.4.3:

[T]he Coordinated System Plan will identify Interregional Projects as: (i) Interregional Reliability Projects, (ii) Interregional Market Efficiency Projects, and (iii) Interregional Public Policy Projects. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the Interregional Project Cost for each such project that is to be allocated to each RTO on behalf of its Market Participants. Interregional Projects can include projects that are: (1) physically located in both the MISO region and the PJM region or (2) physically located wholly in one transmission planning region

61 Id. at PP 89, 94.
62 See Tabs A and B, Proposed JOA sections 9.2.2, 9.3.5.2.b.(v) & 9.3.5.2.b(vi), 9.4.3.1.3, and 9.4.3.2.3.
63 December 18 Order at P 193.
64 Id.
65 See Tabs A and B, Proposed JOA sections 9.4.3.
but jointly determined and agreed upon to provide benefits to the other transmission planning region or both transmission planning regions.\textsuperscript{66}

Adding the Interregional Project type satisfies Cost Allocation Principle 6 by creating a mechanism that accounts for all types of benefits that were identified in MISO’s and PJM’s regional transmission planning processes. An Interregional Project can displace a regional transmission project—be it one driven by reliability, economic, or public policy needs—wherever the Interregional Project is more cost effective than a regional project being considered by both RTOs.\textsuperscript{67} As such, this approach is consistent with the avoided cost methodology that the Commission has accepted in other Order No. 1000 compliance filings.

At the interregional level, Interregional Projects will be cost allocated according to proposed JOA sections 9.4.3.2.1 (Interregional Reliability Projects), 9.4.3.2.2 (Interregional Market Efficiency Projects), and 9.4.3.2.3 (Interregional Public Policy Projects).

For Interregional Reliability Projects, proposed JOA section 9.4.3.2.1 provides:

The cost of an Interregional Reliability Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs an Interregional Reliability Project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region’s displaced reliability projects as agreed to by the RTOs to the total of the present value(s) of the estimated costs of the displaced reliability projects in both regions that have selected the Interregional Reliability Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced reliability project’s estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced reliability projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate proposed by the Transmission Owner that produces the cost estimate for the proposed project. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.\textsuperscript{68}

\textsuperscript{66} Id. at 9.4.3.1.

\textsuperscript{67} See Tabs A and B, Proposed JOA sections 9.4.3.1.1 (Interregional Reliability Projects), 9.4.3.1.2 (Interregional Market Efficiency Projects) and 9.4.3.1.3 (Interregional Public Policy Projects).

\textsuperscript{68} See Tabs A and B, Proposed JOA sections 9.4.3.2.1.
(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region’s respective regional transmission planning process.

For Interregional Market Efficiency Projects, costs shall be allocated between MISO and PJM based on the benefit metric set forth in section 9.4.3.1.2.1.a of the JOA. 69 For Interregional Public Policy Projects, costs shall be allocated between MISO and PJM according to proposed JOA section 9.4.3.2.3, which provides:

The cost of an Interregional Public Policy Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs an Interregional Public Policy Project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region’s displaced public policy projects to the total of the present value(s) of the estimated costs of the displaced public policy projects in both regions that have selected the Interregional Public Policy Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced regional public policy project’s estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced public policy projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate developed by MISO for cost estimates for projects under review by the MISO Board of Directors. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process. 70

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region’s respective regional transmission planning process.

These provisions provide for a fair apportionment of Interregional Project costs to each region according to rules agreeable to both MISO and PJM.

At the regional level, the Filing Parties and PJM propose that each region’s share of an Interregional Project’s cost will be allocated within the region pursuant to the cost allocation

69 Id. at 9.4.3.2.2.

70 See Tabs A and B, Proposed JOA sections 9.4.3.2.3.
methodology contained in each region’s respective regional transmission planning process.\textsuperscript{71} In the MISO region for example, this cost allocation methodology is contained in Attachment FF and is based on the Commission-accepted rules applicable to the types of project being displaced (e.g., Multi Value Project, Market Efficiency Project, or Baseline Reliability Project).\textsuperscript{72}

Taken together, these proposed revisions satisfy the Commission’s directive to account for Interregional Projects addressing reliability, economics and public policy—all of the benefit types that may be identified in the regional transmission planning processes—by directly tying the evaluation and cost allocation of a proposed Interregional Project to framework applicable to the benefit that it provides. As such, this approach has the further advantages of minimizing disruptions to the regional planning process while allowing for the consideration of Interregional Projects on an equivalent footing with their regional counterparts.

\textbf{F. Miscellaneous – Addressing Consistency Issues}

In addition to the tariff revisions discussed above to comply with the \textit{December 18 Order}, PJM proposes ministerial clean up changes to capitalize the word “Section” when referencing a specific section of the JOA.\textsuperscript{73} PJM and MISO also note for clarity that the term “cross-border allocation project” has been replaced throughout the JOA with the term “Interregional Project.”\textsuperscript{74}

\textbf{III. REQUEST FOR WAIVER}

The Filing Parties make this filing in compliance with the Commission’s directives in the December 18 Order. By making this filing in compliance with the December 18 Order, the Filing Parties understand that they have hereby satisfied any of the Commission’s filing requirements that might apply. Should any of the Commission’s regulations (including filing regulations) or requirements that we may not have addressed be found to apply, the Filing Parties respectfully request waiver of any such regulation or requirement.

\textsuperscript{71} See Tabs A and B, Proposed JOA sections 9.4.3.2.1(iii), 9.4.3.2.2 (iii) & 9.4.3.2.3 (iii).

\textsuperscript{72} For Interregional Reliability Projects that displace regional BRPs, the regional methodology is contained in Attachment FF section III.A.2.i.a to MISO’s Tariff. For Interregional Market Efficiency Projects that displace regional MEPs, this methodology is contained in Attachment FF section III.A.2.i.b to MISO’s Tariff. For Interregional Public Policy Projects that displace regional MVPs, this methodology is contained in Attachment FF section III.A.2.i.c to MISO’s Tariff. Note that these sections currently are pending before the Commission in Docket No. ER13-1923-002 (the MISO-SERTP Interregional Coordination docket).

\textsuperscript{73} See Attachment A, JOA §§ 9.3.3(d), 9.4.3.1.2(ii) and (iii) and 9.4.3.1.2.1(c) proposed.

\textsuperscript{74} \textit{Id}. JOA §§ 9.3.5.2(b)(vii), (ix) and (x), 9.4.3.1, 9.4.3.4 proposed.
IV. SERVICE

MISO has served a copy of this filing electronically, including attachments, upon all persons listed on the Commission’s service list for the above-referenced proceeding, Tariff Customers, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, MISO Advisory Committee participants, as well as all state commissions within the Region, and the Organization of MISO States. In addition, the filing has been posted electronically on MISO’s website at https://www.misoenergy.org/Library/FERCFilingsOrders/Pages/FERCFilings.aspx for other parties interested in this matter.

V. SUPPORTING DOCUMENTS

In addition to this Transmittal Letter, the following documents are being submitted with this filing:

- Tab A – Redlined Version of Tariff Sheets
- Tab B – Clean Version of Tariff Sheets

VI. PROPOSED EFFECTIVE DATE

MISO respectfully requests that the proposed Tariff revisions be made effective January 1, 2014, consistent with the effective date ordered by the Commission in the December 18 Order.
VII. CORRESPONDENCE AND COMMUNICATIONS

Correspondence and communications with respect to this filing should be sent to the following persons, who shall also be authorized to receive notice in this docket:

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VIII. CONCLUSION

Wherefore, MISO respectfully requests that the Commission accept this compliance filing and proposed Tariff revisions, effective January 1, 2014 as ordered in the December 18 Order.

Sincerely,

/s/Matthew R. Dorsett
Matthew R. Dorsett
Jacob Krouse
Midcontinent Independent
System Operator, Inc.

Jim Holsclaw
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MISO Transmission Owners
9.2 Data and Information Exchange.

9.2.1 Annual Data and Information Exchange Requirement

In support of interregional planning coordination, each Party shall provide the other with the following data and information on an annual basis and will follow the stipulations for such exchange as noted below.

(a) Power flow models for projected system conditions for the planning horizon (up to the next ten (10) years) that include planned generation development and retirements, planned transmission facilities and seasonal load projections.
(b) System stability models with detailed dynamic modeling of generators and other active elements.
(c) Production cost models for projected system conditions for the planning horizon that include generation and load forecasts and planned transmission facilities.
(d) Assumptions used in development of above power flow, stability and production cost models.
(e) Contingency lists for use in power flow, stability, and production cost analyses.

Models provided will be consistent with those used in the respective Party’s planning processes, including the processes of the NERC Transmission Planners of the Parties as may be necessary for the reviews performed under Section 9.3.5.2. Formats for the exchange of data will be agreed upon by the Parties from time to time. Parties can provide the best available information and will not be required to develop unique models to meet the requirements of this Agreement. Data compiled through other multi-regional modeling efforts can be used to meet the data exchange requirements of this Agreement as agreed to in writing by both Parties. This annual data exchange will be completed during the first quarter of the calendar year, unless Parties agree in writing to a different timeline.

9.2.2 Data and Information Exchange upon Request

In addition to the data and information specified in Section 9.2.1, each Party shall provide the other with the following data and information upon request. Unless otherwise indicated, such data and information shall be provided as requested by either Party, as available, within 30 calendar days from the date of such request or on a mutually agreed to schedule.

(a) Any updates to data exchanged in accordance with Section 9.2.1.

(b) Power flow models and assumptions needed for review of a Parties NERC Transmission Planner proposed plans pursuant to Section 9.3.5.2. Such models and assumptions are those that produce the Bulk Electric System needs of the Transmission Planners in the MISO and PJM regions driving reliability, economic transmission enhancement or expansion, public policy, or operational performance upgrades.

(c) Short-circuit models for transmission systems that are relevant to the coordination of planning between the two Parties.
(c)(d) The regional plan document produced by the Party and any long-term or short-term reliability assessment documents produced by the Party, the timing of each planned enhancement, and estimated in-service dates.

(d)(e) The status of expansion studies, such that each Party has knowledge that a commitment has been made to a system enhancement as a result of any such studies.

(e)(f) Identification and status of interconnection and long-term firm transmission service requests that have been received, including associated studies.

(f)(g) Transmission system maps in electronic or hard copy format for the Party’s bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two Parties.

(g)(h) Such other data and information as is needed for each Party to plan its own system accurately and reliably and to assess the impact of conditions existing on the system of the other Party.
9.3 **Coordinated System Planning.**
The primary purpose of coordinated transmission planning and development of the Coordinated System Plan is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, or enhance the competitiveness of electricity markets, or promote public policy. The Parties will conduct such coordinated planning as set forth in this Section 9.3 and subsections thereof.

9.3.1 **Single Party Planning.**
Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its OATT or as it otherwise shall deem appropriate. Such planning shall conform to applicable reliability requirements of the Party, NERC, applicable regional reliability councils, or any successor organizations, and any and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report that documents its annual regional plan prepared according to the procedures, methodologies, and business rules documented by the region. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, information on requests received from generation resources that plan on permanently retiring or suspending operation consistent with the timelines of each Party’s OATT for such studies, and the identification of proposed transmission system enhancements that may affect the Parties’ respective systems.

9.3.2 **Coordinated System Plan.**
The Coordinated System Plan is the result of the coordination of the regional planning that is conducted under this Agreement. The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan as further described in Section 9.3.5. The Coordinated System Plan shall also include the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party. To the extent that the JRPC agrees to combine with or participate in similarly established joint planning committees amongst multiple planning entities engaging in coordinated planning studies as provided for under Section 9.1.1.2, the coordinated planning analyses of this Protocol may be integrated into any joint coordinated planning analyses engaged in by the multiple parties, provided that the requirements of the Coordinated System Plan are integrated into the scope of such joint coordinated planning analyses.
9.3.3 **Analysis of Interconnection Requests.**

In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. The process for the coordination of studies and Network Upgrades shall be documented in the respective Party’s business practices manuals that are publicly available on each Party’s website. Both Parties’ manual language shall be coordinated so as to ensure the communication of requirements is consistent and includes the following:

(a) Consistent with the data exchange provisions of the manuals, the Parties will exchange current power flow modeling data annually and as necessary for the study and coordination of interconnection requests. This will include the associated update of the other Party’s relevant queue requests, contingency elements, monitoring elements data, and other data as may be required.

(b) The coordination of the study results, pursuant to each Party’s business practices manuals, will determine the potential impact on the direct connect system and on the impacted Party. The direct connect system will be responsible for communicating coordinated interconnection study results to the direct connect interconnection customer.

(c) After reviewing the results, if the potentially impacted Party determines that its system may be materially impacted by the interconnection, that Party will contact the direct connect system and request participation in the applicable interconnection studies. The Parties will coordinate and mutually agree on the nature of studies to be performed to test the impacts of the interconnection on the potentially impacted Party. If the Parties cannot mutually agree on the nature of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV. The Parties will strive to minimize the costs associated with the coordinated study process.

(d) Any coordinated studies will be performed in accordance with the study scope and timeline mutually agreed to in Section 9.3.3 (c) above utilizing the responsibility options outlined in Section 9.3.3 (e) below.

(e) If the coordinated interconnection study identifies constraints that require infrastructure additions on the impacted system to mitigate them, then the potentially impacted Party may perform its own analysis, in conjunction with the direct connect Party’s Interconnection Studies. The interconnection customer whose project requires mitigation of constraint(s) found on an impacted Party’s system shall enter into the
appropriate Facilities Study agreement as required under the impacted Party’s OATT.

(f) The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of such studies and forward collected amounts to the potentially impacted Party.

(g) If the results of the coordinated study process indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such Network Upgrades in the appropriate study report prepared for the interconnection customer.

(h) Requirements for construction of such Network Upgrades will be under the terms of the applicable OATT, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party’s system, then interconnection service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

(j) Each Party will maintain a separate interconnection queue. The Parties will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. These lists will be presented annually to the IPSAC.
9.3.4 Analysis of Long-Term Firm Transmission Service Requests.

In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. The process for the coordination of studies and Network Upgrades shall be documented in the respective Party’s business practices manuals that are publicly available on each Party’s website. Both Parties’ manual language shall be coordinated so as to ensure the communication of requirements is consistent and includes the following:

(a) The Parties will coordinate the calculation of AFC values associated with the service, based on contingencies on the systems of each Party that may be impacted by the granting of the service.

(b) Upon the posting to the OASIS of a request for service, the Party receiving the request will coordinate the study of the request, pursuant to each Party’s business practices manuals, which will determine the potential impact on each Party’s system. The Party receiving the request will be responsible for communicating coordinated study results to the customer requesting such service.

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, and the nature of the service is such that a request on the potentially impacted Party’s OASIS is unnecessary (i.e., the potentially impacted Party is “off the path”), then the potentially impacted Party will contact the Party receiving the request and request participation in the applicable transmission service studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party, who will perform the studies. The Parties will strive to minimize the costs associated with the coordinated study process. The JRPC will develop screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.

(d) Any coordinated studies will be performed in accordance with the mutually agreed upon study scope and timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

(e) If constraints are identified during the coordinated study on the impacted system, then the potentially impacted Party may perform its own analysis in conjunction with the studies performed by the Party that has received
the request for service. The customer whose request for service requires mitigation of constraint(s) found on an impacted Party’s system shall enter into the appropriate facilities study agreement as required under the impacted Party’s OATT. During the Facilities Study, the potentially impacted Party will conduct its own Facilities Study as a part of the Party receiving the request’s Facilities Study. The study cost estimates indicated in the study agreement between the Party receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(f) The Party receiving the request will collect from the transmission service customer and forward to the potentially impacted system the costs incurred by the potentially impacted systems associated with the performance of such studies.

(g) If the results of a coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the Party receiving the request will identify the need for such Network Upgrades in the system impact study prepared for the transmission service customer.

(h) Requirements for the construction of such Network Upgrades will be under the terms of the OATTs, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party’s system, then transmission service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

9.3.5 Development of the Coordinated System Plan.

9.3.5.1 Each Party agrees to assist in the preparation of a Coordinated System Plan applicable to the Parties’ systems. Each Party’s annual transmission planning reports will be incorporated into the Coordinated System Plan, however, neither Party shall have the right to veto any planning of the other Party nor shall either Party have the right, under this Section, to obtain financial compensation due to the impact of another Party’s plans or additions. The Coordinated System Plan will be finalized only after the IPSAC has had an opportunity to review it and respond. The Coordinated System Plan shall:
Integrate the Parties’ respective transmission expansion plans, including any market-based additions to system infrastructure (such as generation, market participant funded, or merchant transmission projects) and Network Upgrades identified jointly by the Parties, together with alternatives to Network Upgrades that were considered;

Set forth actions to resolve any impacts that may result across the seams between the Parties’ systems due to the integration described in the preceding part (a); and

Describe results of the joint transmission analysis for the combined transmission systems, as well as explanations, as may be necessary, of the procedures, methodologies, and business rules utilized in preparing and completing the analysis.

**9.3.5.2**

Coordination of studies required for the development of the Coordinated System Plan will include the following: 1) annual issues review to determine the need for a Coordinated System Plan study described in Section 9.3.5.2.a; and 2) Coordinated System Plan study described in Section 9.3.5.2.b.

Determining the Need for a Coordinated System Plan Study

(i) On an annual basis, the Parties shall perform an annual evaluation of transmission issues identified by each Party, including issues from the respective Party’s market operations and annual planning processes, or Third-Parties. This annual review of transmission issues will be administered by the JRPC on a mutually agreed to schedule taking into consideration each Party’s regional planning cycles. The JRPC through each Party’s respective electronic distribution lists shall provide a minimum of 60 calendar days advance notice of the IPSAC meeting to review identified transmission issues. Stakeholders may identify and submit transmission issues and supporting analysis no later than 30 calendar days in advance of the meeting, for consideration by the IPSAC and JRPC.
Following the annual issues evaluation meeting with IPSAC, the JRPC will determine, taking into consideration input provided by the IPSAC, the need to perform a Coordinated System Plan study. A Coordinated System Plan study shall be initiated by either of the following: (i) each Party in the JRPC votes in favor of performing the Coordinated System Plan study; or (ii) if after two consecutive years in which a Coordinated System Plan study has not been performed, and one Party votes in favor of performing a Coordinated System Plan study. The JRPC shall inform the IPSAC of the decision whether or not to initiate a Coordinated System Plan study.

When a Coordinated System Plan study is determined to be necessary, the JRPC shall agree to the start date of the study, which shall not exceed 180 calendar days from the date of the JRPC’s determination to perform the study, unless the Parties agree to an alternative start date taking into consideration each Party’s regional planning cycles.

(b) Coordinated System Plan Study Process

(i) Each Party will be responsible for providing the technical support required to complete the analysis for the study. The responsibility for the coordinated study and the compilation of the coordinated study report will alternate between the Parties.

(ii) The JRPC will develop a scope and procedure for the coordinated planning analysis. The scope of the studies will include evaluations of issues resulting from the annual coordinated review and analysis of the Parties transmission issues. The scope and schedule for the Coordinated System Plan study will include the schedule of IPSAC review and input at all stages of the study. Study scope and assumptions will be documented and provided to the IPSAC for review and comment.

(iii) Ad hoc study groups may be formed as needed to address localized seams issues or to perform targeted studies of particular areas, needs, or potential expansions and to ensure the coordinated reliability and efficiency of the systems. Under the direction of the Parties, study groups will formalize how activities will be implemented.

(iv) The Coordinated System Plan study will consider the identified
issues reviewed by the JRPC and IPSAC for further evaluation of potential remedies consistent with the criteria of this Protocol and each Party’s criteria. Stakeholder input will be solicited for potential remedies to identified issues, which includes stakeholder and transmission developer proposals for Interregional Projects. The study scope developed under Section 9.3.5.2(b)(ii) will include the schedule for acceptance of such stakeholder Interregional Project proposals including supporting analyses that address issues identified in the JRPC solicitation.

(v) The Parties will document the scope and assumptions including the process and schedule for the conduct of the study. The scope design will include, as appropriate, evaluation of the transmission system against the reliability criteria, operational performance criteria, and economic performance criteria, and public policy needs applicable to each Party.

(vi) The Parties will use planning models that are developed in accordance with the procedures to be established by the JRPC. The JRPC will develop joint study models consistent with the models and assumptions used for the regional planning cycle most recently completed, or underway, as appropriate. If the Coordinated System Plan study requires transmission evaluations driven by different regional needs (for example transmission that addresses any combination of needs including regional reliability, economics and public policy), then the coordination of studies, models, and assumptions will include the analyses appropriate to each region. The Parties will develop compromises on assumptions when feasible and will incorporate study sensitivities as appropriate when different regional assumptions must be accommodated. Known updates and revisions to this models will be incorporated in a comprehensive fashion when new base planning models are available. Prior to the availability of a new comprehensive base model, known updates will be factored in, as necessary, into the review of results. Models will be available for stakeholder review subject to confidentiality and Critical Energy Infrastructure Information (CEII) processes of the Parties. The IPSAC will have the opportunity to provide feedback to the JRPC regarding the study models.

(vii) The IPSAC will have the opportunity to provide input into the development of potential solutions. The JRPC will be responsible for the screening and evaluation of potential solutions, including evaluating the proposed projects for designation as an cross-border allocation Interregional Project pursuant to Section 9.4.3.1.
(viii) Transmission upgrades identified through the analyses conducted according to this Protocol and satisfying the applicable Protocol and regional planning requirements will be included in the Coordinated System Plan after the conclusion of the Coordinated System Plan study and applicable regional analyses. After the conclusion of the Coordinated System Plan study, any project included in the Coordinated System Plan and designated for interregional cost allocation, if not already engaged in the regional review process, will be submitted to the regional processes for review according to Section 9.3.5.2.(x).

(ix) At the completion of the Coordinated System Plan study, the JRPC shall produce a report documenting the Coordinated System Plan study, including the transmission issues evaluated, studies performed, solutions considered, and, if applicable, recommended cross-border allocation Interregional Projects with the associated cost allocation to the Parties pursuant to Section 9.4.3.1. In addition, explanations why proposed Interregional Projects did not move forward in the process will be provided in the final Coordinated System Plan study report. The JRPC shall provide the Coordinated System Plan study report to the IPSAC for review. The IPSAC shall be provided the opportunity to provide input to the JRPC on the Coordinated System Plan study report. The final Coordinated System Plan study report shall be posted on each Party’s website.

(x) The JRPC’s recommended cross-border allocation Interregional Projects identified in the Coordinated System Plan study shall be reviewed by each Party through its respective regional processes. Transmission plans to resolve problems will be identified, included in the respective plans of the Parties and will be presented to the respective Parties’ Boards for approval and implementation using each Party’s procedures for approval. Critical upgrades for which the need to begin development is urgent will be reviewed by each Party in accordance with their procedures and presented to the Parties’ Boards for approval as soon as possible after identification through the coordinated planning process. Other projects identified will be reviewed by each Party in accordance with their procedures and presented to the Parties’ Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade. The JRPC shall inform the IPSAC of the outcome of each Party’s review of the recommended cross-border allocation Interregional Projects.
MISO
MISO RATE SCHEDULES

Section 9.3
Coordinated System Planning
30.0.0, 32.0.0

Effective On: January 1, 2014
9.4 Allocation of Costs of Network Upgrades.

9.4.1 Network Upgrades Associated with Interconnections.

When under Section 9.3.3 it is determined that a generation or merchant transmission interconnection to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party’s OATT.

9.4.2 Network Upgrades Associated with Transmission Service Requests.

When under Section 9.3.4 it is determined that the granting of a long-term firm delivery service request with respect to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party’s OATT.

9.4.3 Network Upgrades Under Coordinated System Plan.

The Coordinated System Plan will identify cross-border Interregional Projects as: (i) CBBRP, or (ii) Interregional Market Efficiency Projects, and (iii) Interregional Public Policy Projects. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the Interregional Project Cost for each such project that is to be allocated to each RTO on behalf of its Market Participants. The JRPC will determine an allocation of costs to each RTO for such Network Upgrades based on the procedures described below. The proposed allocation of costs will be reviewed with the IPSAC and the appropriate multi-state entities and posted on the internet web site of the two RTOs. Stakeholder input will be solicited and taken into consideration by the JRPC in arriving at a consensus allocation of costs.

9.4.3.1 Criteria for Project Designation as an Cross-Border Allocation Interregional Project:

Interregional Projects must be: (1) physically located in both the MISO region and the PJM region or (2) physically located wholly in one transmission planning region but jointly determined and agreed upon to provide benefits to the other transmission planning region or both transmission planning regions. These Interregional Projects will be designated in accordance with the following criteria:

9.4.3.1.1 Criteria for Project Designation as a Cross-Border Baseline Interregional Reliability Project Criteria:

An Interregional Reliability Project must:

(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region’s cost allocation process; and

(ii) Projects that meet all of the following criteria will be designated as CBBRPs: (i) by agreement of the JRPC, the project is needed to displace one or
more reliability projects in either or both PJM and MISO as defined in their respective tariffs and more efficient or cost-effectively meet applicable reliability criteria; (ii) than the project must be a baseline displaced reliability project(s) as defined under the Midwest ISO or PJM Tariffs.

Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Reliability Project(s) addresses reliability needs that are currently being addressed with reliability projects in its regional transmission planning process and, if so, which reliability projects in that regional transmission planning process could be displaced by the proposed Interregional Reliability Project. The analysis of projects that are eligible to be displaced shall only include those projects that have not yet been approved by PJM’s and MISO’s respective Board and made part of the RTO’s respective regional transmission plan.

9.4.3.1.2 Criteria for Project Designation as a Cross-Border Interregional Market Efficiency Project Criteria:

Interregional Market Efficiency Projects that must meet all of the following criteria will be designated as a CBMEP if the project:

(i) has an estimated Project Cost of $20,000,000 or greater;

(ii) is evaluated as part of a Coordinated System Plan or joint study process, as described in Section 9.3.5 of the JOA;

(iii) meets the threshold benefit to cost ratio as prescribed under the terms of, and using the benefit and cost measures prescribed under Section 9.4.3.1.2.1 of the JOA;

(iv) qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a market efficiency project under the terms of Attachment FF of the Midwest ISO OATT (including all applicable threshold criteria), provided that any minimum Project Cost threshold required to qualify a project under either the PJM RTEP or Midwest ISO OATT shall apply the Project Cost of the CBMEP Interregional Market Efficiency Project and not the allocated cost; and

(v) addresses one or more constraints for which at least one dispatchable generator in the adjacent market has a GLDF of 5% or greater with respect to serving load in that adjacent market, as determined using the Coordinated System Plan power flow model.

9.4.3.1.2.1 Determination of Benefits to Each RTO from CBMEP an Interregional Market Efficiency Project:

The RTOs shall jointly evaluate the benefits to the combined Midwest ISO and PJM markets, and to each market individually, by evaluating multiple
metrics using a multi-year analysis to determine whether a proposed project qualifies as an Interregional Market Efficiency Project. The RTOs shall perform this evaluation as follows:

(a) The RTOs shall utilize a benefit metric to analyze the anticipated annual economic benefits of construction of a proposed Interregional Market Efficiency Project to Transmission Customers of each RTO. Benefits are measured for a project by the estimated change in the benefit metric with and without the incorporation of the proposed project. The benefit metric is based upon the impact of the project on: (1) APC (adjusted to account for purchases and sales) and (2) NLP. The benefit metric for each RTO shall be developed by weighting the APC benefit and the NLP benefit. The benefit metric shall be calculated as the sum of seventy percent (70%) times the change in APC benefit for each RTO plus thirty percent (30%) times the change in NLP benefit for each RTO where the change in APC and NLP is calculated by subtracting the APC and NLP values determined without the proposed Interregional Market Efficiency Project:

\[
\text{Benefit Metric} = \left(70\% \times \text{change in APC}\right) + \left(30\% \times \text{change in NLP}\right)
\]

The APC for each RTO represents each RTO’s production costs adjusted for interchange purchases and sales. For each simulation hour in which an RTO is selling interchange, the APC shall be calculated by multiplying the interchange sales MW times the RTO’s generation-weighted LMP and then subtracting this value from the RTO’s production cost. For each simulation hour in which an RTO is purchasing interchange, the APC shall be calculated by multiplying the interchange purchase MW times the RTO’s load-weighted LMP and then adding this value to the RTO’s production cost.

The NLP benefit for each RTO represents each RTO’s gross load payment minus the estimated value of congestion-hedging transmission rights in each RTO. The NLP shall be calculated by multiplying the LMP at each modeled load bus in the RTO by the load (in MW) at the bus, for each simulation hour (load LMP * load (in MW)), and then subtracting from that product the estimated value of congestion-hedging transmission rights for that hour. For each simulation hour, the value of an RTO’s transmission rights shall be calculated by subtracting the RTO generation-weighted LMP from the RTO load-weighted LMP and then multiplying this difference times the lower of the RTO’s total generation MW level or the RTO’s total load MW level.

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The benefit metric shall be calculated for each RTO for each year of simulation. Benefits for intermediate years between simulated years will be based on interpolation. The annual benefit for an Interregional Market Efficiency Project shall be determined as the sum of the benefit values for each RTO. The total project benefit shall be determined by calculating the present value of annual benefits for, at a minimum, the first ten years of project life after the projected in-service year, with a maximum planning horizon of 20 years from the current year.

(b) The RTOs shall employ a threshold benefits-to-costs ratio test to evaluate a potential Interregional Market Efficiency Project. Only projects that meet the benefits-to-costs ratio threshold shall be designated as an Interregional Market Efficiency Project. The costs applied in the benefits-to-costs ratio shall be the present value, over the same period for which the project benefits are determined, of the annual revenue requirements for the project. The annual revenue requirements for the Interregional Market Efficiency Project are determined from the estimated installed costs and the fixed charge rate applicable to the constructing transmission owner(s).

The benefits-to-costs ratio threshold for a project to qualify as an Interregional Market Efficiency Project shall be 1.25 to 1. To determine the present value of the annual benefits and costs, the discount rate shall be based on the transmission owners’ most recent after-tax embedded cost of capital weighted by each transmission owner’s total transmission capitalization. Each transmission owner shall provide the RTOs with the transmission owner’s most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by FERC for comparable facilities.

(c) Using the cost allocated to each RTO pursuant to Section 9.4.3.2.2 of the JOA, and the Coordinated System Plan model, including using the same simulation years, each RTO will evaluate the project using its internal criteria to determine if it qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a market efficiency project under the terms of Attachment FF of the Midwest ISO OATT.

**9.4.3.1.3 Interregional Public Policy Project Criteria:**

Interregional Public Policy Projects must meet the following criteria:
(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region’s cost allocation process; and

(ii) by agreement of the JRPC, displace one or more regional projects addressing public policy in MISO or one or more public policy projects in PJM as defined in their respective tariffs and more efficiently or cost-effectively meet applicable public policy criteria than the displaced regional project(s).

Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Public Policy Project(s) addresses public policy needs that are currently being addressed with public policy projects in its regional transmission planning process and, if so, which public policy projects in that regional transmission planning process could be displaced by the proposed Interregional Public Policy Project. The analysis of projects that are eligible to be displaced shall only include those projects that have not yet been approved by PJM’s and MISO’s respective Board and made part of the RTO’s respective regional transmission plan.

9.4.3.2 Interregional Project Benefits and Cross-Border Project Shares:

The Coordinated System Plan shall designate the share of the Project Cost to be allocated to each RTO as set forth in the following subsections:

9.4.3.2.1 Cost Allocation for Cross-Border Baseline and Interregional Reliability Projects:

a.—For a CBBRP that meets the criteria in Section 9.4.3.1.1 and interconnects to the transmission facilities of a Transmission Owner in MISO and the transmission facilities of a Transmission Owner in PJM, the ownership and responsibility to construct shall be based on the RTO boundaries between the connected Transmission Owners in each RTO, unless otherwise agreed to by such Transmission Owners. Each RTO shall recover the costs associated with the portion owned by its respective Transmission Owner(s) in accordance with the recovery provisions in the applicable Party’s OATT.

b.—For a CBBRP that meets the criteria in Section 9.4.3.1.1 and is located solely within the MISO RTO, the constructing MISO Transmission Owner(s) will work with the PJM Transmission Owner(s) that has/have a reliability-based need that the CBBRP described in this Section 9.4.2.1.b addresses to determine by mutual agreement whether all or a portion of the Network Upgrade Project Cost should be paid for by the PJM Transmission Owner(s). Absent such an agreement
with the PJM Transmission Owner(s), the constructing MISO Transmission Owner(s) has/have the following options:

i. If the CBBRP is not needed to address a reliability issue within the MISO pricing zone(s) where it would be located, the constructing MISO Transmission Owner(s) may elect not to construct the project to address the PJM reliability issue.

ii. If the CBBRP is needed to address a reliability issue within the MISO pricing zone where it would be located, the constructing MISO Transmission Owner(s) may elect to construct the project as a baseline reliability project as defined in the MISO tariff to address the MISO reliability issue.

iii. If the CBBRP is needed to address a reliability issue within the MISO pricing zone where it would be located, as an alternative to 9.4.3.2.1.b.ii, the constructing MISO Transmission Owner(s) has/have the option of working with MISO to identify an alternative Network Upgrade to address the reliability issue in the MISO pricing zone.

e.—For a CBBRP that meets the criteria in Section 9.4.3.1.1 and is located solely within the PJM RTO, the constructing PJM Transmission Owner(s) will work with the MISO Transmission Owner(s) that has/have a reliability-based need that the CBBRP described in this Section 9.4.3.2.1.c addresses to determine by mutual agreement whether all or a portion of the Network Upgrade Project Cost should be paid for by the MISO Transmission Owner(s). Absent such an agreement with the MISO Transmission Owner(s), the constructing PJM Transmission Owner(s) has/have the following options:

i. If the CBBRP is not needed to address a reliability issue within PJM, the constructing PJM Transmission Owner(s) may elect not to construct the project to address the MISO reliability issue.

ii. If the CBBRP is needed to address a reliability issue within PJM, the constructing PJM Transmission Owner(s) may elect to construct the project as a baseline reliability project as defined in the PJM tariff to address the PJM reliability issue.

If the CBBRP is needed to address a reliability issue within PJM, as an alternative to 9.4.3.2.1.c.ii, the constructing PJM Transmission Owner(s) has/have the option of working with PJM to identify an alternative Network Upgrade to address the reliability issue in PJM. The cost of an Interregional Reliability Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs an Interregional Reliability Project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region’s displaced reliability projects as agreed to by the RTOs to the total of the present value(s) of the estimated costs of
the displaced reliability projects in both regions that have selected the Interregional Reliability Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced reliability project’s estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced reliability projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate proposed by the Transmission Owner that produces the cost estimate for the proposed project. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region’s respective regional transmission planning process.

9.4.3.2.2 Cost Allocation for Cross-Border Interregional Market Efficiency Projects:

For CBMEP’s Interregional Market Efficiency Projects that meet all of the qualifications in Section 9.4.3.1.2, the applicable project costs shall be allocated to the respective RTOs in proportion to the net present value of the total benefits calculated for each RTO pursuant to Section 9.4.3.1.2.1(a).

9.4.3.2.3 Cost Allocation for an Interregional Public Policy Project:

The cost of an Interregional Public Policy Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs for an Interregional Public Policy Project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region’s displaced public policy projects to the total of the present value(s) of the estimated costs of the displaced public policy projects in both regions that have selected the Interregional Public Policy Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced regional public policy project’s estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced public policy projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate developed by MISO for cost estimates for
projects under review by the MISO Board of Directors. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region’s respective regional transmission planning process.

9.4.3.3 Determination of Cross-Border Interregional Cost Allocation Share Outside of Coordinated System Plan:

Either RTO may request that a project be tested against the cross-border interregional cost allocation criteria during the interim periods between periodic formal releases of the Coordinated System Plan. The RTOs will conduct reviews between the formal cycles on at least an annual basis. Such tests will be performed on the best available joint planning model, as determined by the JRPC. The joint planning model will be a minimum 5-year horizon case, modeling peak summer conditions, and will be developed by February of each year. It will be based on the current RTEP basecase for PJM and the current MTEP basecase for the Midwest ISO. The basecase developed by each RTO will be based on documented procedures, which, in turn, will guide the development of the joint RTO planning model. Any disputes that arise will be resolved through the dispute resolution procedures documented in Article XIV. Each year the model will be updated by the RTOs to include changes to long term firm transmission service, load forecast, topology changes, generation additions/retirements and any other relevant system changes that may have occurred since the previous years’ basecase development. The joint RTO planning model will be available to any member of PJM or the Midwest ISO.

9.4.3.4 Cost Recovery of Cross-Border Interregional Allocation Shares:

The cost recovery of any share of cost of a cross-border interregional project allocated to either RTO shall be recovered by each RTO according to the applicable tariff provisions of the RTO to which such cost recovery is allocated.

9.4.3.5 Transmission Owners Filing Rights:

Nothing in this Section 9.4 shall affect or limit any Transmission Owners filing rights under Section 205 of the Federal Power Act as set forth in the applicable Tariffs and applicable agreements.

9.4.3.6 Amendments:

The RTOs shall amend Article IX of this Agreement in accordance with the applicable tariffs and/or agreements.

Effective On: January 1, 2014
TAB B
9.2 Data and Information Exchange.

9.2.1 Annual Data and Information Exchange Requirement

In support of interregional planning coordination, each Party shall provide the other with the following data and information on an annual basis and will follow the stipulations for such exchange as noted below.

(a) Power flow models for projected system conditions for the planning horizon (up to the next ten (10) years) that include planned generation development and retirements, planned transmission facilities and seasonal load projections.

(b) System stability models with detailed dynamic modeling of generators and other active elements.

(c) Production cost models for projected system conditions for the planning horizon that include generation and load forecasts and planned transmission facilities.

(d) Assumptions used in development of above power flow, stability and production cost models.

(e) Contingency lists for use in power flow, stability, and production cost analyses.

Models provided will be consistent with those used in the respective Party’s planning processes, including the processes of the NERC Transmission Planners of the Parties as may be necessary for the reviews performed under Section 9.3.5.2. Formats for the exchange of data will be agreed upon by the Parties from time to time. Parties can provide the best available information and will not be required to develop unique models to meet the requirements of this Agreement. Data compiled through other multi-regional modeling efforts can be used to meet the data exchange requirements of this Agreement as agreed to in writing by both Parties. This annual data exchange will be completed during the first quarter of the calendar year, unless Parties agree in writing to a different timeline.

9.2.2 Data and Information Exchange upon Request

In addition to the data and information specified in Section 9.2.1, each Party shall provide the other with the following data and information upon request. Unless otherwise indicated, such data and information shall be provided as requested by either Party, as available, within 30 calendar days from the date of such request or on a mutually agreed to schedule.

(a) Any updates to data exchanged in accordance with Section 9.2.1.

(b) Power flow models and assumptions needed for review of a Parties NERC Transmission Planner proposed plans pursuant to Section 9.3.5.2. Such models and assumptions are those that produce the Bulk Electric System needs of the Transmission Planners in the MISO and PJM regions driving reliability, economic transmission enhancement or expansion, public policy, or operational performance upgrades.

(c) Short-circuit models for transmission systems that are relevant to the coordination of planning between the two Parties.
(d) The regional plan document produced by the Party and any long-term or short-term reliability assessment documents produced by the Party, the timing of each planned enhancement, and estimated in-service dates.

(e) The status of expansion studies, such that each Party has knowledge that a commitment has been made to a system enhancement as a result of any such studies.

(f) Identification and status of interconnection and long-term firm transmission service requests that have been received, including associated studies.

(g) Transmission system maps in electronic or hard copy format for the Party’s bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two Parties.

(h) Such other data and information as is needed for each Party to plan its own system accurately and reliably and to assess the impact of conditions existing on the system of the other Party.
9.3 **Coordinated System Planning.**

The primary purpose of coordinated transmission planning and development of the Coordinated System Plan is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, enhance the competitiveness of electricity markets, or promote public policy. The Parties will conduct such coordinated planning as set forth in this Section 9.3 and subsections thereof.

9.3.1 **Single Party Planning.**

Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its OATT or as it otherwise shall deem appropriate. Such planning shall conform to applicable reliability requirements of the Party, NERC, applicable regional reliability councils, or any successor organizations, and any and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report that documents its annual regional plan prepared according to the procedures, methodologies, and business rules documented by the region. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, information on requests received from generation resources that plan on permanently retiring or suspending operation consistent with the timelines of each Party’s OATT for such studies, and the identification of proposed transmission system enhancements that may affect the Parties’ respective systems.

9.3.2 **Coordinated System Plan.**

The Coordinated System Plan is the result of the coordination of the regional planning that is conducted under this Agreement. The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan as further described in Section 9.3.5. The Coordinated System Plan shall also include the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party. To the extent that the JRPC agrees to combine with or participate in similarly established joint planning committees amongst multiple planning entities engaging in coordinated planning studies as provided for under Section 9.1.1.2, the coordinated planning analyses of this Protocol may be integrated into any joint coordinated planning analyses engaged in by the multiple parties, provided that the requirements of the Coordinated System Plan are integrated into the scope of such joint coordinated planning analyses.
9.3.3 **Analysis of Interconnection Requests.**

In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. The process for the coordination of studies and Network Upgrades shall be documented in the respective Party’s business practices manuals that are publicly available on each Party’s website. Both Parties’ manual language shall be coordinated so as to ensure the communication of requirements is consistent and includes the following:

(a) Consistent with the data exchange provisions of the manuals, the Parties will exchange current power flow modeling data annually and as necessary for the study and coordination of interconnection requests. This will include the associated update of the other Party’s relevant queue requests, contingency elements, monitoring elements data, and other data as may be required.

(b) The coordination of the study results, pursuant to each Party’s business practices manuals, will determine the potential impact on the direct connect system and on the impacted Party. The direct connect system will be responsible for communicating coordinated interconnection study results to the direct connect interconnection customer.

(c) After reviewing the results, if the potentially impacted Party determines that its system may be materially impacted by the interconnection, that Party will contact the direct connect system and request participation in the applicable interconnection studies. The Parties will coordinate and mutually agree on the nature of studies to be performed to test the impacts of the interconnection on the potentially impacted Party. If the Parties cannot mutually agree on the nature of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV. The Parties will strive to minimize the costs associated with the coordinated study process.

(d) Any coordinated studies will be performed in accordance with the study scope and timeline mutually agreed to in Section 9.3.3 (c) above utilizing the responsibility options outlined in Section 9.3.3 (e) below.

(e) If the coordinated interconnection study identifies constraints that require infrastructure additions on the impacted system to mitigate them, then the potentially impacted Party may perform its own analysis, in conjunction with the direct connect Party’s Interconnection Studies. The interconnection customer whose project requires mitigation of constraint(s) found on an impacted Party’s system shall enter into the
appropriate Facilities Study agreement as required under the impacted Party’s OATT.

(f) The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of such studies and forward collected amounts to the potentially impacted Party.

(g) If the results of the coordinated study process indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such Network Upgrades in the appropriate study report prepared for the interconnection customer.

(h) Requirements for construction of such Network Upgrades will be under the terms of the applicable OATT, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party’s system, then interconnection service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

(j) Each Party will maintain a separate interconnection queue. The Parties will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. These lists will be presented annually to the IPSAC.

9.3.4 Analysis of Long-Term Firm Transmission Service Requests.

In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. The process for the coordination of studies and Network Upgrades shall be documented in the respective Party’s business practices manuals that are publicly available on each Party’s website. Both Parties’ manual language shall be coordinated so as to ensure the communication of requirements is consistent and includes the following:
(a) The Parties will coordinate the calculation of AFC values associated with the service, based on contingencies on the systems of each Party that may be impacted by the granting of the service.

(b) Upon the posting to the OASIS of a request for service, the Party receiving the request will coordinate the study of the request, pursuant to each Party’s business practices manuals, which will determine the potential impact on each Party’s system. The Party receiving the request will be responsible for communicating coordinated study results to the customer requesting such service.

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, and the nature of the service is such that a request on the potentially impacted Party’s OASIS is unnecessary (i.e., the potentially impacted Party is “off the path”), then the potentially impacted Party will contact the Party receiving the request and request participation in the applicable transmission service studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party, who will perform the studies. The Parties will strive to minimize the costs associated with the coordinated study process. The JRPC will develop screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.

(d) Any coordinated studies will be performed in accordance with the mutually agreed upon study scope and timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

(e) If constraints are identified during the coordinated study on the impacted system, then the potentially impacted Party may perform its own analysis in conjunction with the studies performed by the Party that has received the request for service. The customer whose request for service requires mitigation of constraint(s) found on an impacted Party’s system shall enter into the appropriate facilities study agreement as required under the impacted Party’s OATT. During the Facilities Study, the potentially impacted Party will conduct its own Facilities Study as a part of the Party receiving the request’s Facilities Study. The study cost estimates indicated in the study agreement between the Party receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.
(f) The Party receiving the request will collect from the transmission service customer and forward to the potentially impacted system the costs incurred by the potentially impacted systems associated with the performance of such studies.

(g) If the results of a coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the Party receiving the request will identify the need for such Network Upgrades in the system impact study prepared for the transmission service customer.

(h) Requirements for the construction of such Network Upgrades will be under the terms of the OATTs, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party’s system, then transmission service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

9.3.5 Development of the Coordinated System Plan.

9.3.5.1 Each Party agrees to assist in the preparation of a Coordinated System Plan applicable to the Parties’ systems. Each Party’s annual transmission planning reports will be incorporated into the Coordinated System Plan, however, neither Party shall have the right to veto any planning of the other Party nor shall either Party have the right, under this Section, to obtain financial compensation due to the impact of another Party’s plans or additions. The Coordinated System Plan will be finalized only after the IPSAC has had an opportunity to review it and respond. The Coordinated System Plan shall:

(a) Integrate the Parties’ respective transmission expansion plans, including any market-based additions to system infrastructure (such as generation, market participant funded, or merchant transmission projects) and Network Upgrades identified jointly by the Parties, together with alternatives to Network Upgrades that were considered;

(b) Set forth actions to resolve any impacts that may result across the seams between the Parties’ systems due to the integration described in the preceding part (a); and
(c) Describe results of the joint transmission analysis for the combined transmission systems, as well as explanations, as may be necessary, of the procedures, methodologies, and business rules utilized in preparing and completing the analysis.

9.3.5.2
Coordination of studies required for the development of the Coordinated System Plan will include the following: 1) annual issues review to determine the need for a Coordinated System Plan study described in Section 9.3.5.2.a; and 2) Coordinated System Plan study described in Section 9.3.5.2.b.

(a) Determine the Need for a Coordinated System Plan Study

(i) On an annual basis, the Parties shall perform an annual evaluation of transmission issues identified by each Party, including issues from the respective Party’s market operations and annual planning processes, or Third-Parties. This annual review of transmission issues will be administered by the JRPC on a mutually agreed to schedule taking into consideration each Party’s regional planning cycles. The JRPC through each Party’s respective electronic distribution lists shall provide a minimum of 60 calendar days advance notice of the IPSAC meeting to review identified transmission issues. Stakeholders may identify and submit transmission issues and supporting analysis no later than 30 calendar days in advance of the meeting, for consideration by the IPSAC and JRPC.

(ii) Following the annual issues evaluation meeting with IPSAC, the JRPC will determine, taking into consideration input provided by the IPSAC, the need to perform a Coordinated System Plan study. A Coordinated System Plan study shall be initiated by either of the following: (i) each Party in the JRPC votes in favor of performing the Coordinated System Plan study; or (ii) if after two consecutive years in which a Coordinated System Plan study has not been performed, and one Party votes in favor of performing a Coordinated System Plan study. The JRPC shall inform the IPSAC of the decision whether or not to initiate a Coordinated System Plan study.

(iii) When a Coordinated System Plan study is determined to be necessary, the JRPC shall agree to the start date of the study, which shall not exceed 180 calendar days from the date of the JRPC’s determination to perform the study, unless the Parties agree to an alternative start date taking into consideration each Party’s regional planning cycles.
(b) Coordinated System Plan Study Process

(i) Each Party will be responsible for providing the technical support required to complete the analysis for the study. The responsibility for the coordinated study and the compilation of the coordinated study report will alternate between the Parties.

(ii) The JRPC will develop a scope and procedure for the coordinated planning analysis. The scope of the studies will include evaluations of issues resulting from the annual coordinated review and analysis of the Parties transmission issues. The scope and schedule for the Coordinated System Plan study will include the schedule of IPSAC review and input at all stages of the study. Study scope and assumptions will be documented and provided to the IPSAC for review and comment.

(iii) Ad hoc study groups may be formed as needed to address localized seams issues or to perform targeted studies of particular areas, needs, or potential expansions and to ensure the coordinated reliability and efficiency of the systems. Under the direction of the Parties, study groups will formalize how activities will be implemented.

(iv) The Coordinated System Plan study will consider the identified issues reviewed by the JRPC and IPSAC for further evaluation of potential remedies consistent with the criteria of this Protocol and each Party's criteria. Stakeholder input will be solicited for potential remedies to identified issues, which includes stakeholder and transmission developer proposals for Interregional Projects. The study scope developed under Section 9.3.5.2(b)(ii) will include the schedule for acceptance of such stakeholder Interregional Project proposals including supporting analyses that address issues identified in the JRPC solicitation.

(v) The Parties will document the scope and assumptions including the process and schedule for the conduct of the study. The scope design will include, as appropriate, evaluation of the transmission system against the reliability criteria, operational performance criteria, economic performance criteria, and public policy needs applicable to each Party.

(vi) The Parties will use planning models that are developed in accordance with the procedures to be established by the JRPC. The JRPC will develop joint study models consistent with the models
and assumptions used for the regional planning cycle most recently completed, or underway, as appropriate. If the Coordinated System Plan study requires transmission evaluations driven by different regional needs (for example transmission that addresses any combination of needs including regional reliability, economics and public policy), then the coordination of studies, models, and assumptions will include the analyses appropriate to each region. The Parties will develop compromises on assumptions when feasible and will incorporate study sensitivities as appropriate when different regional assumptions must be accommodated. Known updates and revisions to models will be incorporated in a comprehensive fashion when new base planning models are available. Prior to the availability of a new comprehensive base model, known updates will be factored in, as necessary, into the review of results. Models will be available for stakeholder review subject to confidentiality and Critical Energy Infrastructure Information (CEII) processes of the Parties. The IPSAC will have the opportunity to provide feedback to the JRPC regarding the study models.

(vii) The IPSAC will have the opportunity to provide input into the development of potential solutions. The JRPC will be responsible for the screening and evaluation of potential solutions, including evaluating the proposed projects for designation as an Interregional Project pursuant to Section 9.4.3.1.

(viii) Transmission upgrades identified through the analyses conducted according to this Protocol and satisfying the applicable Protocol and regional planning requirements will be included in the Coordinated System Plan after the conclusion of the Coordinated System Plan study and applicable regional analyses. After the conclusion of the Coordinated System Plan study, any project included in the Coordinated System Plan and designated for interregional cost allocation, if not already engaged in the regional review process, will be submitted to the regional processes for review according to Section 9.3.5.2(x).

(ix) At the completion of the Coordinated System Plan study, the JRPC shall produce a report documenting the Coordinated System Plan study, including the transmission issues evaluated, studies performed, solutions considered, and, if applicable, recommended Interregional Projects with the associated cost allocation to the Parties pursuant to Section 9.4.3.1. In addition, explanations why proposed Interregional Projects did not move forward in the process will be provided in the final Coordinated System Plan study report. The JRPC shall provide the Coordinated System Plan...
study report to the IPSAC for review. The IPSAC shall be provided the opportunity to provide input to the JRPC on the Coordinated System Plan study report. The final Coordinated System Plan study report shall be posted on each Party’s website.

The JRPC’s recommended Interregional Projects identified in the Coordinated System Plan study shall be reviewed by each Party through its respective regional processes. Transmission plans to resolve problems will be identified, included in the respective plans of the Parties and will be presented to the respective Parties’ Boards for approval and implementation using each Party’s procedures for approval. Critical upgrades for which the need to begin development is urgent will be reviewed by each Party in accordance with their procedures and presented to the Parties’ Boards for approval as soon as possible after identification through the coordinated planning process. Other projects identified will be reviewed by each Party in accordance with their procedures and presented to the Parties’ Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade. The JRPC shall inform the IPSAC of the outcome of each Party’s review of the recommended Interregional Projects.
9.4 Allocation of Costs of Network Upgrades.

9.4.1 Network Upgrades Associated with Interconnections.

When under Section 9.3.3 it is determined that a generation or merchant transmission interconnection to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party’s OATT.

9.4.2 Network Upgrades Associated with Transmission Service Requests.

When under Section 9.3.4 it is determined that the granting of a long-term firm delivery service request with respect to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party’s OATT.

9.4.3 Network Upgrades Under Coordinated System Plan.

The Coordinated System Plan will identify Interregional Projects as: (i) Interregional Reliability Projects, (ii) Interregional Market Efficiency Projects, and (iii) Interregional Public Policy Projects. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the Interregional Project Cost for each such project that is to be allocated to each RTO on behalf of its Market Participants. The JRPC will determine an allocation of costs to each RTO for such Network Upgrades based on the procedures described below. The proposed allocation of costs will be reviewed with the IPSAC and the appropriate multi-state entities and posted on the internet web site of the two RTOs. Stakeholder input will be solicited and taken into consideration by the JRPC in arriving at a consensus allocation of costs.

9.4.3.1 Criteria for Project Designation as an Interregional Project:

Interregional Projects must be: (1) physically located in both the MISO region and the PJM region or (2) physically located wholly in one transmission planning region but jointly determined and agreed upon to provide benefits to the other transmission planning region or both transmission planning regions. These Interregional Projects will be designated in accordance with the following criteria:

9.4.3.1.1 Interregional Reliability Project Criteria:

An Interregional Reliability Project must:

(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region’s cost allocation process; and

(ii) by agreement of the JRPC, displace one or more reliability projects in either or both PJM and MISO as defined in their respective tariffs and more efficiently or cost-effectively meet applicable reliability criteria than the displaced reliability project(s).
Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Reliability Project(s) addresses reliability needs that are currently being addressed with reliability projects in its regional transmission planning process and, if so, which reliability projects in that regional transmission planning process could be displaced by the proposed Interregional Reliability Project. The analysis of projects that are eligible to be displaced shall only include those projects that have not yet been approved by PJM’s and MISO’s respective Board and made part of the RTO’s respective regional transmission plan.

9.4.3.1.2 Interregional Market Efficiency Project Criteria:

Interregional Market Efficiency Projects must meet the following criteria:

(i) has an estimated Project Cost of $20,000,000 or greater;

(ii) is evaluated as part of a Coordinated System Plan or joint study process, as described in Section 9.3.5 of the JOA;

(iii) meets the threshold benefit to cost ratio as prescribed under the terms of, and using the benefit and cost measures prescribed under Section 9.4.3.1.2.1 of the JOA;

(iv) qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a market efficiency project under the terms of Attachment FF of the Midwest ISO OATT (including all applicable threshold criteria), provided that any minimum Project Cost threshold required to qualify a project under either the PJM RTEP or Midwest ISO OATT shall apply the Project Cost of the Interregional Market Efficiency Project and not the allocated cost; and

(v) addresses one or more constraints for which at least one dispatchable generator in the adjacent market has a GLDF of 5% or greater with respect to serving load in that adjacent market, as determined using the Coordinated System Plan power flow model.

9.4.3.1.2.1 Determination of Benefits to Each RTO from an Interregional Market Efficiency Project:

The RTOs shall jointly evaluate the benefits to the combined Midwest ISO and PJM markets, and to each market individually, by evaluating multiple metrics using a multi-year analysis to determine whether a proposed project qualified as an Interregional Market Efficiency Project. The RTOs shall perform this evaluation as follows:

(a) The RTOs shall utilize a benefit metric to analyze the anticipated annual economic benefits of construction of a proposed Interregional Market Efficiency Project to Transmission Customers of each RTO.

Effective On: January 1, 2014
Benefits are measured for a project by the estimated change in the benefit metric with and without the incorporation of the proposed project. The benefit metric is based upon the impact of the project on: 

(1) APC (adjusted to account for purchases and sales) and (2) NLP.

The benefit metric for each RTO shall be developed by weighting the APC benefit and the NLP benefit. The benefit metric shall be calculated as the sum of seventy percent (70%) times the change in APC benefit for each RTO plus thirty percent (30%) times the change in NLP benefit for each RTO where the change in APC and NLP is calculated by subtracting the APC and NLP values determined without the proposed Interregional Market Efficiency Project:

\[
\text{Benefit Metric} = (70\% \text{ of change in APC} + 30\% \text{ of change in NLP})
\]

The APC for each RTO represents each RTO’s production costs adjusted for interchange purchases and sales. For each simulation hour in which an RTO is selling interchange, the APC shall be calculated by multiplying the interchange sales MW times the RTO’s generation-weighted LMP and then subtracting this value from the RTO’s production cost. For each simulation hour in which an RTO is purchasing interchange, the APC shall be calculated by multiplying the interchange purchase MW times the RTO’s load-weighted LMP and then adding this value to the RTO’s production cost.

The NLP benefit for each RTO represents each RTO’s gross load payment minus the estimated value of congestion-hedging transmission rights in each RTO. The NLP shall be calculated by multiplying the LMP at each modeled load bus in the RTO by the load (in MW) at the bus, for each simulation hour (load LMP * load (in MW)), and then subtracting from that product the estimated value of congestion-hedging transmission rights for that hour. For each simulation hour, the value of an RTO’s transmission rights shall be calculated by subtracting the RTO generation-weighted LMP from the RTO load-weighted LMP and then multiplying this difference times the lower of the RTO’s total generation MW level or the RTO’s total load MW level.

The benefit metric shall be calculated for each RTO for each year of simulation. Benefits for intermediate years between simulated years will be based on interpolation. The annual benefit for an Interregional Market Efficiency Project shall be determined as the sum of the benefit values for each RTO. The total project benefit shall be determined by calculating the present value of annual benefits for, at a minimum, the first ten years of project life after the projected in-
service year, with a maximum planning horizon of 20 years from the current year.

(b) The RTOs shall employ a threshold benefits-to-costs ratio test to evaluate a potential Interregional Market Efficiency Project. Only projects that meet the benefits-to-costs ratio threshold shall be designated as an Interregional Market Efficiency Project. The costs applied in the benefits-to-costs ratio shall be the present value, over the same period for which the project benefits are determined, of the annual revenue requirements for the project. The annual revenue requirements for the Interregional Market Efficiency Project are determined from the estimated Interregional Market Efficiency Project installed costs and the fixed charge rate applicable to the constructing transmission owner(s).

The benefits-to-costs ratio threshold for a project to qualify as an Interregional Market Efficiency Project shall be 1.25 to 1. To determine the present value of the annual benefits and costs, the discount rate shall be based on the transmission owners’ most recent after-tax embedded cost of capital weighted by each transmission owner’s total transmission capitalization. Each transmission owner shall provide the RTOs with the transmission owner’s most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by FERC for comparable facilities.

(c) Using the cost allocated to each RTO pursuant to Section 9.4.3.2.2 of the JOA, and the Coordinated System Plan model, including using the same simulation years, each RTO will evaluate the project using its internal criteria to determine if it qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a market efficiency project under the terms of Attachment FF of the Midwest ISO OATT.

9.4.3.1.3 Interregional Public Policy Project Criteria:

Interregional Public Policy Projects must meet the following criteria:

(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region’s cost allocation process; and

(ii) by agreement of the JRPC, displace one or more regional projects addressing public policy in MISO or one or more public policy projects in PJM as defined in their respective tariffs and more efficiently or cost-effectively meet applicable public policy criteria than the displaced regional project(s).
Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Public Policy Project(s) addresses public policy needs that are currently being addressed with public policy projects in its regional transmission planning process and, if so, which public policy projects in that regional transmission planning process could be displaced by the proposed Interregional Public Policy Project. The analysis of projects that are eligible to be displaced shall only include those projects that have not yet been approved by PJM’s and MISO’s respective Board and made part of the RTO’s respective regional transmission plan.

**9.4.3.2 Interregional Project Benefits and Shares:**

The Coordinated System Plan shall designate the share of the Project Cost to be allocated to each RTO as set forth in the following subsections:

**9.4.3.2.1 Cost Allocation for an Interregional Reliability Project:**

The cost of an Interregional Reliability Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs an Interregional Reliability Project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region’s displaced reliability projects as agreed to by the RTOs to the total of the present value(s) of the estimated costs of the displaced reliability projects in both regions that have selected the Interregional Reliability Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced reliability project’s estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced reliability projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate proposed by the Transmission Owner that produces the cost estimate for the proposed project. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region’s respective regional transmission planning process.

**9.4.3.2.2 Cost Allocation for an Interregional Market Efficiency Project:**

Effective On: January 1, 2014
For Interregional Market Efficiency Projects that meet all of the qualifications in Section 9.4.3.1.2, the applicable project costs shall be allocated to the respective RTOs in proportion to the net present value of the total benefits calculated for each RTO pursuant to Section 9.4.3.1.2.1(a).

9.4.3.2.3 Cost Allocation for an Interregional Public Policy Project:

The cost of an Interregional Public Policy Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs for an Interregional Public Policy Project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region’s displaced public policy projects to the total of the present value(s) of the estimated costs of the displaced public policy projects in both regions that have selected the Interregional Public Policy Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced regional public policy project’s estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced public policy projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate developed by MISO for cost estimates for projects under review by the MISO Board of Directors. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region’s respective regional transmission planning process.

9.4.3.3 Determination of Interregional Cost Allocation Share Outside of Coordinated System Plan:

Either RTO may request that a project be tested against the interregional cost allocation criteria during the interim periods between periodic formal releases of the Coordinated System Plan. The RTOs will conduct reviews between the formal cycles on at least an annual basis. Such tests will be performed on the best available joint planning model, as determined by the JRPC. The joint planning model will be a minimum 5-year horizon case, modeling peak summer conditions, and will be developed by February of each year. It will be based on the current RTEP basecase for PJM and the current MTEP basecase for the Midwest ISO. The basecase developed by each RTO will be based on documented procedures, which, in turn, will guide the development of the joint
RTO planning model. Any disputes that arise will be resolved through the dispute resolution procedures documented in Article XIV. Each year the model will be updated by the RTOs to include changes to long term firm transmission service, load forecast, topology changes, generation additions/retirements and any other relevant system changes that may have occurred since the previous years’ basecase development. The joint RTO planning model will be available to any member of PJM or the Midwest ISO.

9.4.3.4 Cost Recovery of Interregional Allocation Shares:

The cost recovery of any share of cost of an Interregional Project allocated to either RTO shall be recovered by each RTO according to the applicable tariff provisions of the RTO to which such cost recovery is allocated.

9.4.3.5 Transmission Owners Filing Rights:

Nothing in this Section 9.4 shall affect or limit any Transmission Owners filing rights under Section 205 of the Federal Power Act as set forth in the applicable Tariffs and applicable agreements.

9.4.3.6 Amendments:

The RTOs shall amend Article IX of this Agreement in accordance with the applicable tariffs and/or agreements.